STATE OF VERMONT

BEFORE THE PUBLIC SERVICE BOARD

Green Mountain Power	**)**	Docket No. 6107
Rate-Increase Request	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE DEPARTMENT OF PUBLIC SERVICE

Resource Insight, Inc.

SEPTEMBER 18, 1998

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I. Identification and Qualifications

Q: Please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am president of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February, 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters. My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is appended to this testimony as Exhibit DPS-PLC-1.

Q: Have you testified previously on utility resource planning?

A: Yes. I have testified on the prudence of utility supply and DSM decisions in many jurisdictions in the United States and Canada. My resume details this experience.

Q: Have you testified previously before the Board?

A: Yes. I testified in

- Docket No. 4936, on Millstone 3;
- Docket No. 5270 on DSM cost-benefit test, preapproval, cost recovery, incentives, and related issues;
- Docket No. 5330, on the conflict between the HQ purchase and DSM;
- Docket No. 5491, on the need for HQ power and the costs of alternative purchases;
- Docket No. 5686, on the avoided costs and water-heater load-control programs of Central Vermont Public Service (CVPS);
- Docket No. 5724, on CVPS avoided costs;
- Docket No. 5835, on design of CVPS of load-management rates;
- Docket No. 5980, on avoided costs for statewide DSM programs;
- Docket No. 5983, on Green Mountain Power's distributed-utility planning, past avoided costs, and the prudence of its decisions with respect to its purchases from Hydro Québec;
- Docket No. 6018, on CVPS's distributed-utility planning, current avoided costs, and the prudence of its decisions with respect to its purchases from Hydro Québec.

Q: On whose behalf are you testifying?

A: This testimony is filed on behalf of the Vermont Department of Public Service ("DPS" or "the Department").

II. Introduction and Summary

Q: What is the purpose of this testimony?

A: My testimony primarily responds to a series of questions that the Board raised in its order in Docket No. 5983 with respect to the damages that resulted from GMP's decision to lock into the HQ-VJO purchase prematurely, in August 1991. In this connection, I explain why the conclusions of GMP witnesses Oliver and Higgins on the damages resulting from the premature lock-in are incorrect.

In addition, I place in perspective certain arguments about the application of the prudence test raised by GMP witness Reed and witnesses Oliver and Higgins. I also update the Board regarding the status of GMP's Distributed Utility planning efforts.

Q: Please summarize your testimony on the cost of GMP's imprudence.

A: While it is impossible to determine exactly what sequence of events would have occurred, had GMP and the VJO acted prudently with regard to the HQ-VJO contract, some outcomes are clear. Green Mountain Power would not have locked into the HQ-VJO contract early, or even by the November 30, 1991 deadline. Either HQ would have granted the VJO an extension of the lock-in date, as it did for New York (which agreed with HQ on a one-year extension at the same time GMP was agreeing to the lock-in), or the VJO would have canceled the contract prior to November.

If the lock-in deadline had been extended into 1992, prudent analyses of the contracts economics would have more definitely established that it was uneconomic.[1] Green Mountain Power (and probably the VJO as a whole) would either have negotiated a significantly cheaper, shorter, smaller, and/or more flexible contract with HQ, or they would have canceled.

Following the cancellation of the HQ-VJO contract, GMP would have been in the position of several utilities that were actively seeking power-supply arrangements in 1992. Had GMP acted prudently at that time, it would have diversified its supply sources and contract structures, and contracted for a variety of supplies. It would also have increased its emphasis on energy conservation, rather than curtailing its DSM programs in 1994 in response to the low avoided costs resulting from GMP's excessive commitment to the HQ contract.

Q: How much lower would GMP's power-supply costs be today if GMP had prudently managed its power supply?

A: Depending on the exact mix of base, intermediate, and peaking resources; the duration of each contracts; and the details of contract pricing that GMP could have negotiated, prices of individual contracts in 1999 might vary from 3¢/kWh to 5¢/kWh. A portion of the contracts would probably be expiring in the next year or so, allowing GMP to obtain power at current market prices. The contracts (or schedules within contracts) with low capacity costs and

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[1]On May 29, 1991, CVPS responded to a Unitil RFP with an offer to sell Schedule B at full cost through 2015. This suggests that CVPS knew that it had more HQ than it needed for the long term, and suspected that it would not be able to sell it at more than cost, as it had predicted in Docket No. 5330. Sometime late in 1991 (the winners were not known in time for the 11/91 issue of *Current Competition*, but were listed in the 2/92 issue), Unitil rejected CVPS's proposal in favor of purchases from NU, UI, NEES, and MMWEC. At that point, at least CVPS had evidence from the market that it could not sell HQ power at full cost, and that there were cheaper alternatives.

expensive energy would be very close to market pricing, since GMP would use little of the high-priced contract energy, taking most of its supply from the market. Finally, GMP's supply would be much more closely matched to its requirements, and its would not have a surplus of high-priced power to sell into a weak market.

Q: Do the analyses sponsored by GMP witnesses Oliver and Higgins provide useful information about the costs of GMP imprudence?

A: No. To the extent that their testimony addresses this issue, it is not useful in judging the cost of GMP's imprudence with respect to the HQ contract. They present a series of the analyses of the cost-effectiveness of the HQ contract from the perspective of 1991–92, but do not demonstrate that those analyses represent the approach that would have been taken by a prudent utility in that period. Hence, their analyses provide no information about the resource commitments that were likely to result from a prudent supply-planning process. In addition, many of their inputs, assumptions, and computations are incorrect or misapplied.

Oliver and Higgins reach the conclusion that GMP would have selected the HQ contract over alternative resources, due mainly to the externality values they use. They do not explore how much GMP might have been able to secure in pre–lock-in sellbacks or other side concessions in negotiations during 1991 and 1992, as the economics of the HQ contract (based on the direct costs other potential buyers would have been using) deteriorated compared to alternatives.

Nor do Oliver and Higgins show the costs today of having selected other resources in the past. Their only analysis at today's costs is their used-and-useful analysis, which compares the HQ contract to current projections of spot market prices.

Q: Do the GMP witnesses provide other useful information relevant to judging the prudence of GMP's actions, and the reasonableness of its costs?

A: No. It is my understanding that the Board has determined that GMP was imprudent in locking into the HQ contract, and that the only related issues in this docket have to do with determining what a prudent utility would have done in GMP's situation, and how much lower costs would be today as a result. Yet GMP Witness Reed repeats the assertions about the nature of the appropriate prudence standard that he and Oliver made in Docket No. 5983, and which the Board found unconvincing. Similarly, both Reed and Oliver and Higgins appear to dispute the Board's finding of that GMP was imprudent in its management of the HQ contract in 1991. Even if these arguments were relevant, they are internally inconsistent and based on fatally flawed analyses.

Q: Please summarize your conclusions related to the used-and-useful test for the HQ-VJO purchase.

A: Oliver and Higgins argue that the HQ-VJO purchase, while it is uneconomic for ratepayers on a direct-cost basis, is societally economic due to environmental and non-price benefits. Their claims of environmental benefits are incorrect and unsupported. Their claims of non-price benefits are vague and unquantified; they do not even establish that the contract's net non-price benefits are positive.

Q: Please summarize your conclusions regarding Distributed Utility planning.

A: The Company continues along the course that I described in Docket No. 5983: delaying implementation of DUP while developing complex models that cannot possibly address the really difficult issues in DU planning; running a case study for a constrained area and declaring the solution to be found, even though the assumptions and results are obviously incorrect; and deferring targeted DSM and detailed distributed generation planning until it is likely to be too late to be useful. The EPRI model for which GMP promised so much in Docket No. 5783 has proven no more useful in the Dover-Wilmington study than did the previous GMP model in the Mad River Valley study.

The utility continues to focus on developing models, rather than reducing energy use and avoiding unnecessary future T&D investments.

Q: Please describe the structure of the remainder of your testimony.

A: The next section presents my summary of the likely effect of prudent resource-planning behavior on the part of GMP in 1991 and 1992, and the current cost of GMP's imprudence. That section also discusses the effect of environmental externalities on the current value of the contract. Section IV deals with errors in the inputs, assumptions and computations in Oliver and Higgins's testimony, to the extent that their analyses might be taken to be concerned with the outcomes of a prudent resource-planning process after the avoidance of the premature lock-in in August 1991. Section V describes other prudence issues that are raised by the Reed testimony and Oliver and Higgins's testimony. Section VI updates the Board regarding the status of GMP's Distributed Utility planning efforts.

III. Least-Cost Planning and the Damages of Imprudence

A. Least-Cost Planning: HQ-VJO After August 1991

Q: If GMP had prudently chosen not to lock into the HQ-VJO contract prematurely in August 1991, what would it have done thereafter?

A: Green Mountain Power should have been using the three months remaining before the lock-in date to re-examine the economics of the HQ contract, to determine whether, in light of the conditional approvals received in Canada and Vermont, the contract was sufficiently advantageous.

The utility should have been soliciting detailed bids from potential alternative suppliers, in New England and New York, as well as exploring with HQ any opportunities for reducing the cost, magnitude, duration, and inflexibility of the HQ-VJO contract.[2] Green Mountain Power should also have been comparing the cost of the HQ-VJO contract to those alternatives.

Q: What would GMP have found at that time?

A: After August 1991, Green Mountain Power came to place more weight on the "low" fuel price used in its September 1991 IRP and less on the "base" forecast received from WEFA in May 1991, which GMP considered "conservatively high" even in the IRP. By April 1992, the 1991 "low" forecast had become GMP's base forecast. At these lower fuel prices, the HQ-VJO contract would be substantially more expensive than previously identified fossil-fueled purchases and new plants.

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[2]For example, GMP should have been resolving any ambiguities in NU's offer, concerning the mixes of capacity NU was willing to offer and the periods for which that capacity could be obtained.

Green Mountain Power also would have found that NYSEG and NiMo were offering capacity and energy, at least through 1999, at prices competitive with those available from New England utilities, but with different price structures, as shown in Exhibit DPS-PLC-2.

Q: What other considerations would GMP need to apply under the requirements of Least Cost Planning?

A: Green Mountain Power would need to consider the environmental costs or benefits of the HQ contract, compared to other resources, and the non-price (i.e., risk-related) benefits or costs.

Q: What were the relative environmental benefits of the HQ contract, compared to other existing and new resources?

A: The environmental effects of the HQ contract depend on what would have happened to the power had the VJO canceled the contract. The possibilities are that

- HQ would have spilled water over the dams, unable to sell it,
- the dams that would have provided the energy would not have been built,
- the power would have been sold to New England in short-, mid- and long-term contracts, or
- the power would have been sold to other utilities in the Northeast, in short-, mid- and long-term contracts.

The first possibility would not occur to any significant extent. HQ has a large amount of storage, and has never appeared to be in any danger of not finding a market for its power.

The Board rejected the second possibility, at least with regard to the minimum 340-MW purchase, which would be supplied by dams that would have been built anyway, on essentially the same schedule (Docket No. 5330, at 175-177).[3]

Hence, the effect of the purchase would be that HQ would sell less power off system in economy sales and other shorter-term arrangements, principally to New England, New York, and New Brunswick. Indeed, one of the effects of the VJO contract (recognized by GMP, the DPS, and the Board) was that the Vermont utilities would reduce their entitlement in the existing HQ-NEPOOL Phase II purchase.

Since the HQ-VJO purchase used energy that otherwise would have been sold to some other buyers (which I will call “Other Buyers”) in New England or adjacent regions, the HQ-VJO purchase must have required the Other Buyers to use more energy from existing fossil generation to meet their loads. Whether GMP purchased power from HQ, a New York utility, or a New England utility, the dispatch of power plants and the environmental effect would be essentially the same. The flow of contract dollars within New England does not determine the flow of electrons, or the dispatch of power plants. Regardless of whether GMP contracted for power from HQ or from NU, for example, when NEPOOL dispatched power resources to meet

[3]This appears to have been true, in hindsight. The dams that HQ has added since the VJO lock-in were all under construction at the time of the lock-in. The largest hydro projects then planned (Great Whale and NBR) were subsequently canceled; HQ solicited bids from IPPs in 1991 and selected about 1,000 MW, mostly from new gas-fired plants. It is not clear to what extent this IPP solicitation was driven by the export market, and to what extent it was the result of a political or strategic decision to develop an IPP market in Quebec. It is possible that the HQ-VJO sale resulted in that addition of some new gas-fired generation in Quebec. Additional dams under construction or planned today are clearly competing with the Northeastern regional power market (from which HQ could otherwise purchase power, and into which it will sell any excess), and would have been equally likely to be constructed with or without the VJO contract.

regional needs, it would dispatch essentially the same mix of NU power plants, other New England power plants, imports from HQ, and other imports. The environmental effect of the HQ purchase should thus be similar to the externalities from purchases within New England, which I discuss below.[4]

Q: Could GMP have acquired any resource in 1991–92 that would have provided environmental benefits, compared to purchases from HQ, New York, or NEPOOL utilities?

A: Yes. If GMP actually caused a clean new generator (e.g., a new renewable or gas combined-cycle plant) to be built before it was otherwise needed or economical, that power would be cleaner than the regional supply.[5] Those actions are generally expensive, but would be justified at sufficiently high externalities.

Q: What were the other non-price benefits and costs of the HQ contract?

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[4]If the power would otherwise have been sold to New York, it would have resulted in reduced usage of gas-, oil- and coal-fired generation in New York, and probably would have reduced imports of coal-fired power from PJM and Ontario Hydro. Some of the New York generation freed up by that hypothetical purchase would have been sold to New England, but transmission constraints and imperfections in coordination of dispatch between NYPP and NEPOOL might have limited the amount of increased sales to New England. In this case, the environmental effects of the HQ-VJO contract might well have been worse than the effects of purchases from within NEPOOL.

[5]By 2000, the marginal regional supply will be new gas combined-cycle (as was expected in 1991), so the advantages of accelerated introduction of gas combined-cycle are limited to the 1990s.

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commitment to fixed costs, and its vulnerability in the event that fuel prices

[6]Delivery of power is subject to the availability of transmission facilities in Québec, as well as to the sufficiency of HQ resources to meet native loads and other firm obligations.

[7]Green Mountain Power Corporation 1996 Annual Report to Shareholders, p. 12.

[8]Most of GMP’s other resources have some fixed costs.

or demand fell. In a period of low fuel prices, GMP is stuck with high capacity costs and take-or-pay energy from several sources, including HQ.[9] In a period of low demand, GMP must pay for all the capacity and energy charges from HQ and small power producers, as well as all the costs of the hydro plants and most of the costs of Vermont Yankee, even if it does not need the energy.

The Company and CVPS both testified in Docket No. 5330 that the risks of the HQ contract were mitigated by their certainty that they could resell any temporarily-excess HQ power at a profit. By late 1991, that assurance no longer existed. Indeed, it was likely by that time that HQ power could not be resold for full cost, even over the entire life of the contract.

Q: Please summarize the non-price benefits of the HQ-VJO purchase, compared to alternatives available in the early 1990s.

A: The HQ-VJO purchase did not have a clear net advantage over any other resource. The price risks of the HQ-VJO purchase were quite real, especially as its advantages on an expected-cost basis evaporated in late 1991, but are difficult to compare consistently to the risks of other resources. Environmentally, the HQ-VJO purchase was essentially equivalent to purchases from other existing or committed resources in New England or New York, and somewhat inferior to new clean resources (particularly gas-fired combined-cycle) installed prior to 2000.

[9]So little of Vermont Yankee costs are avoidable from reducing output that its energy costs might as well be take-or-pay.

Q: What environmental externalities should be included in comparing the HQ purchase to the market value of energy, from the current perspective?

A: It is now clear that there is no significant difference between the environmental effects of the HQ purchase and other purchases from the regional energy market. The treatment of externalities in Oliver and Higgins's testimony is clearly incorrect and cannot be relied on for determining the cost-effectiveness of the HQ purchase. The flows of power and the dispatch of power plants would be very similar, regardless of whether Green Mountain Power were purchasing power from HQ, from NU, from NYSEG, or from a previously committed IPP, such as Altresco Pittsfield or Milford. In any of these cases, GMP's load results in additional fossil generation at the NEPOOL or Northeastern margin.[10]

If a contract from Green Mountain Power had resulted in construction of an IPP, such as Cogen LR or WESNEEX, that would not otherwise have been developed, the resulting emissions would be the lower emission rates of new gas combined-cycle plants.

B. The Cost of GMP's Imprudence

Q: Were any New England utilities in the position that GMP would have been in had it rejected the HQ contract: seeking power supply in the early 1990s?

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[10]Since the power pools are not perfectly interconnected, and economy interchange may not be perfectly efficient, the avoided externalities might be slightly higher if the power were sold to New York, with more coal on the margin, than to New England.

A: Yes. Some of the other Vermont utilities, such as Burlington Electric, rejected their HQ elections, or have been otherwise short on capacity since 1991. Several Massachusetts municipals and Unitil have also needed to acquire additional power supply in this period. These utilities have generally purchased power in the short and medium term, essentially at market prices.

In late 1991, Unitil selected the winners in its April 1991 RFP.[11] Unitil rejected CVPS's offers of Schedule B at cost, in favor of purchases from NU, UI, NEES, and MMWEC.[12] Unitil selected a mix of oil, gas (steam and combined-cycle), coal, and nuclear; from six utilities, nine plants, and eleven units; and with expiration dates ranging from April 2001 to April 2013. Over half the capacity was in contracts that would expire in 2005-2006. This is a reasonable model for prudent behavior by GMP in a later period. Exhibit DPS-PLC-3 shows the 1997 cost of each of Unitil's commitments made in this period, at its actual capacity factor and adjusted to 75% capacity factor, assuming that additional energy would purchased or sold at $25/MWh. Each of the Unitil purchases was less expensive than the HQ-VJO contract; the average purchase cost 5¢, 25% less than HQ.

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[11]This was somewhat earlier than GMP would have been likely to act on replacement power, since Unitil needed large amounts of power (it contracted for about 90 MW, compared to a system peak of about 300 MW) in 1993 and GMP perceived no major need until 1995. In addition, if GMP had started looking for power to replace HQ in the fall of 1991, the Unitil schedule suggests that it would have taken about 8 months, or into the summer of 1992, to select winners. Since prices were generally falling, GMP was likely to get better deals and to select a mix that used more oil and gas and less fixed costs. GMP also had a large nuclear commitment in Vermont Yankee, and was not likely to be eager to increase its nuclear exposure.

[12]At some point, it added a purchase from Great Bay Power, as well.

Exhibit DPS-PLC-4 summarizes the provisions of ten contracts signed by eight New England municipal utilities in 1992 or 1993 to purchase power over periods of 5-12 years from Boston Edison, NEPCo, or NU.[13] The contracts are generally structured as system power purchases, although the prices are sometimes tied to fuel prices at a particular plant and availability of energy is sometimes conditioned on the availability of at least one or two of a group of plants. The inter-utility contracts also generally have greater flexibility in energy take and capacity adjustment than the HQ contract, and have shorter terms as well. If they turn out to be somewhat above market prices, they will not last as long as the HQ contract and will therefore produce much lower damages.

The actual costs (as the resource were dispatched for NEPOOL billing purposes) generally fell in the range of 3–5.5¢/kWh in 1997, with a simple average of 4.6¢/kWh, compared to 6.5¢/kWh for the HQ purchase.[14] Of the seven contracts for which I have been able to project prices for 1999, the prices range from 4.1–5¢/kWh at current energy forecasts. As importantly, the 1997 prices would have been 4.3–5¢/kWh with the WEFA 9/92 forecast or GMP's own 1992 fuel-price forecast. The highest-cost purchase in each of

[13]I have not included unit power purchases priced at cost-of-service, or contracts that appear to have been continuations of older contracts or resolutions of disputes. The cost projections do not include contracts that are difficult to price or evaluate, such as those based on cost of service. The costs of the NEPCo-Littleton and NEPCo-Braintree contracts include compensation for NEPCo's payment to buy out the Newbay NUG contract; I have reduced the projected capacity cost to reflect pricing without the Newbay payment (about $60/kW-yr., or 1¢/kWh).

[14]This comparison nets out the Newbay buyout charges in some NEPCo contracts, and omits the NEPCo-Reading contract (at 6.5¢/kWh), which seems to have been used by Reading at a very low load factor in 1997.

the projections is the sale by NU to Madison, Maine—a requirements sale, including reserves, charging the purchaser only for actual load, and allowing the purchaser to change loads as required. Requirements contracts are more valuable, and should generally be priced higher, than firm power sales.

In 1995, the Burlington Electric Department negotiated contracts with NU and New York State Electric and Gas (NYSEG) for purchases from May 1998 through 2007 and 2009, respectively. The contracts, signed in March 1996, are described in Exhibit DPS-PLC-5 and Exhibit DPS-PLC-6. The prices that Burlington Electric Department would pay in 1998 under these contracts are equivalent to $30-$33/MWh at the 75% capacity factor of the HQ-VJO contract. The Burlington contracts represent very flexible power-supply arrangements. There is no minimum energy take, energy is a majority of the purchase price, and energy prices vary between peak and off-peak. Burlington has the option of changing the capacity of the purchases over a wide range, on two months notice: from 2.5 MW to 7.5 MW for the NU contract, and 3 to 10 MW for the NYSEG contract. Under these circumstances, the sellers cannot count on above-market (or above-cost) prices in one year balancing below-market prices in another year; the annual prices in the contract must represent a reasonable approximation of the price at which the seller would have been willing to sell in that year, for any length contract.

Q: Were similar power supply options available from New York utilities in 1991 and 1992?

A: As discussed above, attractive terms were available from NiMo and NYSEG as early as early 1992 (see IR IBM 3-294). The NYSEG A offer was entirely fixed in price, and would have been subject to cancellation by either party after 1999. The NiMo B offer included fixed capacity prices and oil-based energy prices, while the NYSEG B and NiMo A offers included fixed capacity costs and some form of marginal energy costs. The NYSEG A was one of the lowest-cost options available, and the NiMo A offer was also competitive with other options.

Q: Which of these supply sources should GMP have selected?

A: Green Mountain Power should have negotiated with potential suppliers to develop a low-cost and diverse portfolio. To maximize the benefits and minimize risk, GMP probably should have selected purchasers with the following characteristics:

- several suppliers (including a shorter, cheaper, and more flexible purchase from HQ, if it was still interested),
- a mix of start dates or ramp-up schedules to meet projected requirements (rather than the abrupt jumps and excess capacity of the HQ purchase),
- a mix of contract durations and options for contract capacity reduction or cancellation,
- some options for increasing capacity,
- a variety of pricing mechanisms (fixed prices, prices tied to inflation, prices tied to fuel prices).[15]

While no one can determine today exactly what GMP resource mix would have resulted from a prudent power-supply negotiation and acquisition process in 1991–92, this would be the general nature of the optimal mix.

Q: What would those alternative purchases have cost?

[15]Green Mountain Power would also have pursued more DSM, had it behaved prudently.

A: That obviously depends on exactly what combination of resources GMP would have purchased in the early 1990s

Some of the purchases would probably have include energy charges that are now above the market price in most hours. For example, while the NYSEG A offer would have been attractive as an intermediate resource in 1991 or 1992, it would be dispatched as a peaker in 1998 and 1997. Hence, most of this resource would consist of market energy purchases, with the purchase capping energy costs at the contract price; since the capacity charges are not much higher than market capacity costs, the cost of the NYSEG A offer would be equal to, or only a few mills higher than the market.

Municipal-utility purchases from NEPCo and NU, committed in the period in which GMP was likely to be buying, cost about 4¢/kWh in 1997 with 10-yr. contract, which is very close to today's market price. The one example of a five-year contract cost about 3¢, substantially below the market price.

Contracts signed in a period after 1993 would be less expensive than the current market, as demonstrated by the BED contracts.

Q: What portion of the current above-market costs of the HQ purchase are due to the imprudence of Green Mountain Power in 1991?

A: Most of the above-market costs of the HQ purchase could have been avoided had GMP chosen not to lock into the HQ contract early. The resources that replaced the HQ contract would have been at least the 25% less expensive, as the Board assumed in Docket No. 5983. It is also reasonable to believe that the mix of resources would have been comparable in cost to current market prices, which in 1999 would be almost 40% less than the cost of the HQ contact. Hence, 25%–40% of the HQ contract costs are due to the imprudence of GMP.

IV. Errors in Oliver and Higgins's Testimony

Q: How do Oliver and Higgins address the estimation of the damages that resulted from the early lock-in decision?

A: While the purpose of their testimony is not entirely clear, Oliver and Higgins may have attempted to demonstrate that no costs were imposed by GMP's imprudent lock-in decision, by demonstrating that prudent planning would have led GMP to commit to the HQ contract in decision in 1991 or 1992.

Q: Do they accomplish that objective?

A: No. Oliver and Higgins's computations are of little practical value, for the following reasons:

- The methods and inputs in Oliver and Higgins's analyses do not represent the approach that GMP would have used if it had behaved prudently. Oliver and Higgins do not use the best assumptions that were (or should have been) available to GMP. Their approach is frequently inconsistent with the practice and beliefs of both GMP and Oliver and Higgins at the time, and in some cases may represent a position no one has ever taken.
- Oliver and Higgins present little more than illustrative computations, since neither they nor any other GMP witness testifies as to the applicability of their assumptions and inputs.
- They rehash issues on which GMP put on stronger cases that were rejected by Board in Docket No. 5983.

- Oliver and Higgins rely on GMP witnesses in Docket No. 5983, without purporting to provide independent analysis.
- Oliver and Higgins use values they did not, and do not, believe, and that GMP did not, and does not, believe.
- Their externality assumptions and computations are incorrect.
- Their analyses contain many errors: conceptual, logical, factual, and mathematical.

Q: In what areas are Oliver and Higgins's analyses inappropriate or incorrect for the purpose of determining which resources GMP would have selected to replace the HQ-VJO contract?

A: Their analyses contain a number of problems, including

- the choice of fuel prices;
- the selection of resource alternatives analyzed, and the prices assumed for those resources;
- externalities;
- the construction and modeling of the resource portfolios.

In addition, they make many errors in their computations.

A. Fuel Prices

Q: What fuel prices did Oliver and Higgins use in their analyses?

A: They used the following three sets of fuel prices:

- WEFA's May 1991 forecast developed for GMP, and used in the 1991 IRP;
- a forecast of fuel prices relevant to GMP's alternatives, developed by Oliver and Higgins from the WEFA Winter 1991–92 forecast;

- a fuel forecast developed by WEFA for GMP in September 1992.[16]

Oliver and Higgins (IR DPS 2-33) assert that they compared these forecasts to others developed in the same period and found them to be consistent, but were unable to provide the fuel-price forecasts used in that comparison.

Q: Does this represent the set of fuel prices that GMP would have used in a prudent analysis of alternatives in late 1991 and 1992?

A: No. They do not provide much useful information in determining what resources GMP would have selected, had it been prudently comparing the HQ-VJO contract to alternatives in this period.

As shown in Exhibit DPS-PLC-7, the WEFA May 1991 and Winter 1991–92 price projections were higher than the fuel prices that GMP actually believed in late 1991 and 1992.[17] While GMP called the WEFA May 1991 forecast its “base” fuel-price forecast in the 1991 IRP, GMP also described this forecast as “conservatively high” and developed a “low” fuel-price projection by combining the WEFA May 1991 short-term low-price forecast with the long-term escalation rates from the low case in the WEFA 1989 forecast (1991 IRP at 7-2).

In April 1992, GMP cited with approval the avoided-cost projections of New England Power and the New York Power Pool. The corresponding fuel-price forecasts were much lower than the WEFA forecasts; indeed, the price of gas in the NEPCo forecast was lower than in the GMP “low” forecast.

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[16]Oliver and Higgins claim that GMP had a 1992 forecast from WEFA that GMP denied having in Docket No. 5983.

[17]The WEFA September 1992 fuel-price was roughly comparable to GMP’s 1991 “low” forecast.

In short, at the time that GMP would have been evaluating alternatives to the HQ-VJO contract (had it not locked into the contract prematurely), prudent analysis would have relied on the fuel prices GMP believed most likely.[18] A sensitivity range around those fuel prices might also be useful in assessing the risk of alternative resources.

Q: Did GMP actually rely on the "low" fuel-price forecast in 1991-92?

A: Yes. In the 1991 IRP, GMP conducted extensive analyses of DSM and post-HQ supply resources (but not HQ) under low fuel prices in the IRP.

The IRP included all of the collaboratively designed DSM programs (to which GMP had already agreed).[19] Within six months of the filing of the IRP (and five months after the HQ lock-in deadline), GMP decided that the low-fuel-price was its best estimate. GMP then produced new avoided energy costs, using the low fuel-price projection and lower market energy prices, which led to the determination that four of the DSM programs were not cost-effective.

In a September 21, 1992 letter to Dr. Steinhurst of the DPS, Mr. Saintcross described the new fuel-price forecast further:

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[18]Of course, this conclusion would not hold if GMP's beliefs about fuel prices were themselves imprudent. That was not the case: GMP's projections were within the range of fuel prices expected by other utilities. Oliver and Higgins do not dispute the reasonableness of GMP's preferred fuel-price projection.

[19]Green Mountain Power did not commit to the post-HQ supply acquisitions that were recommended under the "base" fuel prices, perhaps because those resources were not least-cost under the "low" fuel prices.

> This forecast, absent any consideration of…continued economic decline and depressed fuel prices, is the same low forecast of fuel prices employed in the October 1991 IRP, which to date has not been challenged by parties to Docket No. 5270-GMP-4.
>
> The current economic slowdown in New England has reduced future demand and energy projections of GMP and most New England utilities…. Changes in the world oil situation and pricing have evolved over the same time period.
>
> These economic changes necessitated a comprehensive reassessment of the vale of power supply resources…to ensure that least-cost planning is maintained by an economically justified blend of supply- and demand-side resources. (GMP 1991 IRP at 6-1)

That "comprehensive reassessment" for DSM included the use of the low fuel-price forecast.

Q: What rationale do Oliver and Higgins offer for ignoring the fuel-price forecast that GMP actually used in late 1991 and 1992?

A: As Oliver and Higgins explain (IR DPS 2-38), their justification for not using the "low" forecast was based on Saintcross's rebuttal in Docket No. 5983 (at 45), in which he asserted that the "low" price forecast was used only for short-term decisions (comparing the NU purchase to Cogen LR) and for DSM programs with lives of 7 to 8 years. Oliver and Higgins offer no new information or original analysis on the applicability of GMP's "low" forecast in supply planning.

I responded to Saintcross's assertions in my own rebuttal in Docket No. 5983, and pointed out that there was no significant difference between the lifetimes of the HQ contract and the resources evaluated at the "low" fuel price projection. Neither the purchases nor the DSM were short-term decisions. The NU and Cogen LR purchases would start in November 1994 (the same as HQ) and continue for 10 and 20 years, respectively. None of the

DSM programs was expected to have effects that lasted as little as 7–8 years; the shortest-lived program had an expected life of 8.7 years, most were expected to last 11–16.5 years, and one was expected to last over 30 years, far longer than the HQ purchase.[20]

Oliver and Higgins also assert that "it is meaningless to consider a low fuel-price forecast without also considering the corresponding high fuel-price forecast." (IR DPS 2-43). As I pointed out in my direct testimony in Docket No. 5983, the 1991 "low" price forecast was really GMP's *base* case for most of the relevant period. Even if the "low" case was a sensitivity at the time of the premature lock-in, GMP considered its "base" case to be "the corresponding high fuel-price forecast" that Oliver and Higgins demand. Oliver and Higgins misinterpret the high "base" case as a best estimate, and ignore the "low" case.

B. Alternative Resources

Q: What classes of alternative resources do Oliver and Higgins consider

A: They compare the HQ contract to various combinations of utility purchases, non-utility generators, and utility-owned plants.

1. Utility Purchases

Q: What are problems in the treatment of utility purchases in Oliver and Higgins's testimony?

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[20] Oliver and Higgins claim to have reviewed my rebuttal testimony in Docket No. 5983 (IR DPS 2-157). They have not explained why they chose to ignore the facts that I presented and rely on unfounded opinion of Saintcross instead.

A: Oliver and Higgins estimate the busbar costs of five utility purchases: capacity and energy from the spot market, three variations of the NU 1991 offer to GMP, and the UI sale to Unitil. The prices for the spot market and the NU offer were taken from the GMP 1991 IRP, but Oliver and Higgins have refused to provide any documentation for the UI-Unitil transaction. I have not yet been able to determine whether they properly modeled the UI-Unitil sale. Nor have they provided any documentation for the wheeling costs assumed for each option.[21]

I have identified the following problems with the treatment of utility purchases in Oliver and Higgins's testimony.

- While Oliver and Higgins computed busbar costs for the NU capacity mix as proposed by NU, and the intermediate (all oil) and baseload mixes developed by GMP, they did not determine the busbar costs of the least-cost NU mix. In Docket No. 5983, I demonstrated that the most favorable NU purchase would have included the intermediate oil plants and the Northfield Mountain pumped-storage plant.

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[21]Oliver and Higgins include $15/kW-yr. for NU and $12.21/kW-yr. for PSNH (without explaining why the power from Connecticut and Massachusetts plants would be wheeled through PSNH) for a total of $27.21/kW-yr. for the NU options and Bridgeport Harbor 3; $3/kW-yr. for New Haven Harbor; $23.21/kW-yr. (composed of unidentified $12.21 and $11/kW-yr. components) for Altresco; $9/kW-yr. for Enron and new utility-owned plants; $15/kW-yr. for spot purchases; and zero for HQ and Vermont IPPs. These wide unexplained disparities in wheeling rates can have a significant effect on estimated resource costs. If the $9/kW-yr. value was the appropriate value for the NU purchase, for example, that resource would be considerably less expensive than Oliver and Higgins assumed.

- Oliver and Higgins do not develop any method for computing the benefits of energy storage at Northfield Mountain,[22] or of dual-fuel capability at West Springfield 3.
- They incorrectly weight energy costs in some generation mixes. For example, they assume that all three intermediate units would operate at the same capacity factor, even though the energy cost of one unit (West Springfield 3) is 25% higher than the cost of the other two. Similarly, they assume that nuclear, oil, and pumped-storage plants would all operate at the same capacity factor in the NU mix, and that the coal-fired Bridgeport Harbor 3 and the oil-fired New Haven Harbor would operate at the same capacity factor in the UI-Unitil contract.
- Oliver and Higgins incorrectly weighted GMP’s 1991 estimates of spot energy prices. In the IRP, Green Mountain Power assumed that the 1991 spot price would average $36/MWh in four winter months and $29/MWh in the rest of the year, for an average cost of $31.3/MWh. Oliver and Higgins simply averaged the two values, and used $32.5/MWh as its starting price.
- Perhaps most importantly, they ignore the option of purchases from New York. The power sales offered by New York utilities were some of the lowest-cost offers.

[22]Busbar analyses are not very useful in comparing storage options with baseload, since the value of pumped storage depends on what other resources are available. Oliver and Higgins do not include Northfield in any of the portfolios they evaluate.

2. Availability of Transmission from New York

Q: Do Oliver and Higgins offer any rationale for not considering any utility purchases from New York?

A: Their only basis for this omission is to quote the testimony of Bolbrock in Docket No. 5983. Oliver and Higgins offer no independent analysis of New York transmission availability, and rely entirely on Bolbrock testimony to justify their reliance on Bolbrock (IR DPS 2-85, 2-86, and 2-104).

Q: Was Bolbrock correct in Docket No. 5983?

A: No. Mr. Bolbrock considerably exaggerated the problems that would have faced GMP in importing power from New York. I explained some of those problems in my rebuttal testimony in Docket No. 5983. The Board found that substantial import capacity was generally available (Docket No. 5983 at 201).

Oliver and Higgins do not offer any basis for ignoring the record in Docket No. 5983, or the Board's order.

Q: Were imports from New York generally assumed to be available to New England utilities in the early 1990s?

A: Yes. For example, in 1994, Mr. Reed found that Boston Edison could count on as much as 750 MW of capacity from New York, even if it did not reserve capacity or transmission in advance (Exhibit DPS-PLC-8).

Q: Was transmission from NY available to GMP in 1991 and 1992?

A: Yes. In his direct testimony in Docket No. 5983, Mr. Bolbrock conceded that GMP had access to 42–53 MW of transmission from New York, out of a total of 168–210 MW for Vermont.[23] In the same proceeding, Saintcross (direct at 36) said that Vermont had access to 220 MW in the winter (when it would have been most valuable to GMP), and 170 MW in the summer, and that GMP had 50 MW reserved for its purchase from RG&E through 1997. The NY-NEPOOL tie was used largely for economy purchases, over which a firm purchase would take priority.

Q: Did Bolbrock's testimony in Docket No. 5983 demonstrate that long-term New York to NEPOOL power transfers were believed in 1991 to be much more constrained than Mr. Reed found in 1994?

A: No. Bolbrock's direct and rebuttal raised general concerns about the possible effect of possible new NUGs in eastern New York on NYPP-NEPOOL power flows, and noted that certain constraints existed on the NEPOOL side of the interface. His testimony did not demonstrate any continuing problems.

Q: Did Bolbrock show that eastern New York NUGs would have a significant effect on New York to NEPOOL power transfers?

A: No. His 1/9/98 rebuttal testimony (at 2) presented an April 1991 memo (Exhibit GMP-RJB-2) that expressed concern about the effect of a particular proposed NUG, but noted that capacity on the interface was not heavily used: "With the recent decrease in power demand, the commissioning of Seabrook, the Construction of Phase II and the acceleration of DSM efforts, the demand for transmission from New York has largely evaporated."[24] A later report

[23]The range appears to reflect summer (low end) and winter (high end) conditions.

[24]Bolbrock filed rebuttal on 12/8/97 and 1/9/98, and identified his exhibits in both pieces as GMP-RJB-[number], starting (on both cases) with number 1. Since the first piece of rebuttal had four attached exhibits, there are two different exhibits labeled GMP-RJB-1, two labeled

(Exhibit GMP-RJB-1) largely put those concerns to rest, noted that the NY-NEPOOL interface was not heavily used: only 8 hours in the last two years were over 1000 MW (Exhibit GMP-RJB-1 at 1). The plant about which Bolbrock expressed such concern would only cause problems when New York was buying a lot of power from HQ, and Highgate was shut down. Neither condition was common.[25]

Q: Are you aware of any other utility reports on the effects of NY NUGs on the NY-NEPOOL interface in this time period?

A: Yes. Niagara Mohawk, which was a major seller of power to New England and had every reason to keep transmission capacity open, reported in its September 1991 IRP (at 6–15) that the NYPP-NEPOOL Interface "is currently limited by lines in New England which may be upgraded in the future…Subject to specific study, new [NUG] resources in Eastern NY are not anticipated to be detrimental to the NYPP-NEPOOL Interface and, unless shown to be detrimental to Central-East requirements, should not be discouraged."

Q: Were Bolbrock's observations about internal NEPOOL limits on NY-NEPOOL power transfers a valid source of concern about the availability of long-term power purchases?

A: No. Bolbrock (1/9/98 rebuttal at 4, line 24) noted that transmission capacity in the Summer of 1990 varied from 0 to 1100 MW, based on a report he

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GMP-RJB-2, and so on. In my testimony, I respond to Bolbrook's testimony and exhibits of 1/9/98 only.

[25]Other documents that Bolbrock cited as the basis for his concerns discussed "possible but improbable risks," the "rare circumstances [in which a proposed plant]…may increase the costs of maintaining compliance," and the effects "under certain severe and improbable…conditions.

attached as Exhibit GMP-RJB-3. Mr. Bolbrock also provided a report (Exhibit GMP-RJB-4) with data on limits for the NY-NEPOOL interface for Summer 1991. This limit was less serious than the limit in 1990, with limits of 1,100-1,500 MW. Both reports indicate that the limiting element—the line that could be overloaded—was the Oswald Tap–Woodland Road circuit." NU's system plans at the time indicated that it intended to upgrade that line in 1991.

Bolbrock also provided similar data for Winter 1991 (Exhibit GMP-RJB-5). Those limits were much higher than the Summer 1990 and Summer 1991 limits, 1,600–1,800 MW. The limiting factor was then the Plumtree-Newtown line. NU had scheduled an upgrade of that line for 1992.

Q: What transfer limits were reported for the NY-NEPOOL interface in the mid-1990s?

A: In 1994–96, NEPOOL reported transfer limits of 1,300–2,000 MW in its annual FERC Form No. 715.

Q: Was NYPP-NEPOOL transmission capacity expensive in the early 1990s?

A: No. NYSEG estimated a cost of $24/kW-yr. in 1992 (IR IBM 3-294 at 9), which would be about $4/MWh. Green Mountain Power paid about $3/MWh for NYPA to wheel power from Ontario Hydro in 1990 through 1993, and about $8/MWh to wheel its RG&E purchase through NiMo and NU in 1990. The NU charges for transmission of the RG&E entitlement fell to less than

1¢/MWh in 1991, and less than $1/MWh in 1992 (GMP FERC Forms 1 for various years at 332).[26]

Q: At what prices were New York utilities offering power in the 1991–92 time frame?

A: In early 1992, New York State Electric and Gas (NYSEG) and Niagara Mohawk (NiMo) provided CVPS with power offers (IR IBM 3-294). Each utility made two offers; one of the NYSEG offers is based on a complex definition of marginal energy costs and is difficult to evaluate. The other three offers are priced out in Exhibit DPS-PLC-2.[27] I included the highest transmission charges Oliver and Higgins estimated for any purchase ($27.71/kW-yr.), which is somewhat higher than NYSEG's estimate of the transmission cost. The real-levelized costs of the less expensive of these offers were 3.8-4.5¢/kWh in 1991 dollars, considerably below the 4.8–4.9¢/kWh cost of Schedules B and C of the HQ contract.

3. Non-Utility Purchases

Q: Did Oliver and Higgins properly model non-utility purchase options?

A: That is difficult to determine. Oliver and Higgins failed to provide the derivation of the prices they used for Cogen LR, WESNEEX, Altresco, and Enron (IR DPS 2-125; IR IBM 3-289, 3-290).

The workpapers provided in IR IBM 3-289 consist of three pages from an exhibit to Reed and Oliver's 12/8/97 testimony in Docket No. 5983,

[26]The NiMo transmission charge appears to have been a fixed capacity charge of $22.80/kW-yr.

[27]I used NiMo's estimate of its marginal energy costs in evaluating NiMo A.

which show estimates of WESNEEX costs developed by GMP in July 1991. Those estimates are not the same as the values used by Oliver and Higgins for WESNEEX, even for the same fuel-price forecast. Where the assumptions in IR IBM 3-289 are similar to those underlying Exhibit WJO/JEH-7, it appears that Oliver and Higgins used the prices that GMP estimated for the power year starting in November as if they were the prices in effect for the calendar year, effectively increasing prices by one year's inflation.

Oliver and Higgins provide no sources whatsoever for any of the other NUG offers or contracts. It is possible that their Cogen LR assumptions are consistent with documents provided in Docket No. 5983; I have not had time to search out these documents and determine whether they can be reconciled to the assumptions of Oliver and Higgins.[28] The pricing of the Altresco-Pittsfield sale to Commonwealth Energy appears to be from CommEnergy's 10/90 RFP, prior to the decline in fuel prices and fuel-price projections in 1991, and also appears to be higher than the pricing of Altresco's January 1992 bid to Boston Edison from its proposed Lynn plant.

I cannot determine whether Oliver and Higgins properly estimated the costs of these options from the information available to them, or available to GMP at the time.

[28]This process would have been much simpler if Oliver and Higgins had simply provided their derivation of contract prices.

4. New Utility Power Plants

Q: Were there any problems in Oliver and Higgins's treatment of new utility-owned plants?

A: I have identified three such problems in the treatment of new utility CTs and combined-cycle plants.

First, Oliver and Higgins use inconsistent assumptions about the utility's cost of capital. They take the carrying cost of the plants from the NEPOOL's "Generation Task Force Long-Range Planning Assumptions" for 1991, which assumed a 10.8% cost of capital, but discount at an assumed utility cost of capital of 10.2%. The resulting PV costs of the utility plants those costs are higher than they would have been if either the 10.8% or 10.2% value had been used consistently for both purposes.

Second, Oliver and Higgins incorrectly calculate capacity costs in cents per kWh based on dollars per kW-yr. for the CT and combined-cycle. While they properly convert other resources' capacity costs to cents per kWh by dividing by 8760 (the hours in the year) and by the capacity factor, they compute the CC and CT cost per kWh as the dollars-per-kW-yr. charge divided by 8760 and *multiplied* by the capacity factor.

Oliver and Higgins use an implausibly high price for gas pipeline capacity.

Q: Why do you say that Oliver and Higgins used pipeline costs that were too high?

A: Oliver and Higgins assumed pipeline demand costs of $1.60/MMBtu, which is equivalent to $584/MMBtu-day of pipeline capacity or $117/kW-yr. of combined-cycle capacity (at their assumed heat rate) in 1990 dollars.[29] They assumed that the pipeline costs would escalate at the general inflation rate to the in-service date of each combined-cycle unit. This pipeline cost is nearly half of their estimate of the total annual fixed costs of a baseload combined-cycle unit. This value is much too great.

- In the early 1990s, pipeline fixed charges were generally more like \$200/MMBtu-day.
- The 1989 NEPOOL Generation Task Force (GTF) "Long-Range Planning Study Assumptions" reported a pipeline fixed charge of \$1/MMBtu, with no escalation, either to the power plant's installation date or afterward.
- In its 4/1/91 report, the NEPOOL GTF reduced its estimate of pipeline fixed charges to \$0.65/MMBtu in 1990 dollars, inflated to the in-service date and held constant thereafter.

C. *Externalities*

Q: What aspects of the treatment of externalities by Oliver and Higgins will you discuss?

A: In the subsequent sections, I discuss the problems with Oliver and Higgins's understatement of the emissions that would result from the HQ-VJO purchase, their overstatement of the emissions resulting from other resources, their choice of externality values in dollars per ton, and their use of a radically lower discount rate for emission costs than for other costs.

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[29]This is \$1.60 per MMBtu of gas deliverability to the plant, and would be paid regardless of the extent to which the plant actually operated. At a 75% capacity factor, the cost is about \$2.13 per MMBtu actually used.

1. Emissions Due to the HQ-VJO Purchase

Q: How did Oliver and Higgins determine the externalities of the HQ contract?

A: Oliver and Higgins use the estimate of CO_2 emissions from flooding of reservoirs in Québec reported by the PSB in Docket No. 5330 (at 186). Oliver and Higgins implicitly assume that the effect of the VJO purchase was to flood more reservoirs.[30]

Q: What information do Oliver and Higgins present on the effect of the HQ-VJO contract on generation dispatch in the Northeast?

A: They have no information and no opinion concerning the fate of the HQ energy, had the contract been canceled, either from an historical perspective or today (IR DPS 2-52).

2. Emissions from Other Resources

Q: For what other generation resources did Oliver and Higgins estimate environmental emissions, and what was the source of those estimates?

A: Oliver and Higgins used emission values for coal plants from the order in Docket No. 5330 (at 182), and emissions for oil-steam, gas-steam, combustion turbines, and new gas combined-cycle plants from the Department's filing in Docket No. 5980.[31]

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[30]They also ignore the environmental effects of the reservoirs, other than the CO_2 emissions.

[31]I use the term "steam plant" to refer to facilities that generate electricity by burning fuel to produce steam, which turns a steam turbine, which turns a generator. Most large pre-1990 fossil plants are steam plants. Combustion turbines burn fuel and use the hot gases to turn a turbine (like that in a jet engine). Combined-cycle plants combine these technologies, burning fuel to

They made the following assumptions:

- The externalities of a purchase would be determined by the plants specified in the contract.
- Purchases on the spot market would be entirely oil-steam throughout the period.
- The energy for pumping water into the Northfield pumped-storage plant would be 56% oil-steam, 8% gas-steam, and 36% coal.
- Purchases from New York would be primarily from coal.

Q: What analyses do Oliver and Higgins provide to support their assumptions?

A: None.

Q: Did Oliver and Higgins use appropriate estimates of emissions?

A: No. Many of their assumptions are incorrect and unreasonable. One group of errors involves confusions about timing and vintage, as follows:

- Oliver and Higgins assume that the emissions from a new combustion turbine would be the same as from the existing mix. This was an unreasonable assumption in 1991, due to better heat rates, lower-NOx burners, and greater use of gas by new CTs. The existing combustion turbines are primarily from the early 1970s, and frequently operate at heat rates of 16,000 BTU/kWh or more; the 1991 NEPOOL GTF projected that new units would have full-load heat rates of 10,000–12,000 BTU/kWh.

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turn a combustion turbine, and using the still-hot gas to boil water to turn a steam turbine. Most generation installed since 1990, or currently planned, is combined-cycle.

- Similarly, Oliver and Higgins use an estimate of existing-plant coal emissions provided by a VJO witness in Docket No. 5330, apparently based on emissions of some plant (or group of plants) prior to the 1990 Amendments to the Clean Air Act, which required reductions in SO_2 and NOx emissions. State regulations imposed additional limitations. Oliver and Higgins's emissions are 6 lb./MWh NOx and 47.8 lb./MWh SO_2. By 1995, the largest coal-fired plant in New England, NEPCo's Brayton Point, had emissions of 2.7 lb./MWh NOx and 12.53 lb./MWh SO_2. Future values will be even lower across the region.[32]
- Similarly, Oliver and Higgins assume no improvements in emissions from oil- and gas-fired steam plants, as they are affected by state and federal regulations.
- By 1991, it was clear that oil was not on the margin in all hours for NEPOOL. Some formerly oil-fired plants were burning gas much of the year, and more gas conversions were planned. Gas-fired combined-cycle plants, mostly IPPs but also future utility-owned plants, were expected to be at the margin some of the time as well.[33] For example, in my April 1994 testimony in Docket No. 5270 CV-1 and -3, I projected a marginal steam-plant mix of 76% oil, 19% gas-steam, and 5% gas combined-cycle, gradually shifting to 45% oil, 32% gas, and 23% gas

[32]Most New England and New York coal units will not be affected by the CAAA acid-rain requirements until 2000.

[33]This seemed more likely at the higher gas prices expected in 1991. At today's prices, gas combined-cycle units may be dispatched before coal plants.

combined-cycle by 2014.[34] Thus, emissions from the NEPOOL margin would have been cleaner than Oliver and Higgins assumed.

- Oliver and Higgins assumed in their retrospective analyses (Exhibits WJO/JEH 6 and 7) that GMP could continue purchasing from the spot market without contributing to construction of new (and inevitably cleaner) capacity. Realistically, additional demand would eventually result in the suppliers adding capacity. Given what GMP believed about regional capacity needs in 1991, that transition would occur about the year 2000.[35] After 2000, purchases from existing or previously committed sources would result in combined-cycle emissions, rather than the NEPOOL margin. The DPS estimates of externalities that Oliver and Higgins use in their Exhibit WJO/JEH-8 include this effect, and drop substantially in 2000.

A second group of errors involved Oliver and Higgins failure to understand the nature of utility dispatch.

- Purchases from utilities within NEPOOL, whether from the spot market, the NU offers, or the UI-Unitil contract, would result in additional generation of the marginal NEPOOL supply until the purchase resulted in new construction, at which time the incremental emissions would be those of the new unit. Oliver and Higgins have no basis for assuming that spot purchases would be entirely from oil, NU purchases designated as being from Connecticut Yankee would produce no air

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[34]I also estimated that CTs would provide 5% of the margin in 1994 and 15% in 2014. My estimates for 1994 were based on the NEPOOL marginal emissions estimated by Tellus in Docket No. 5330.

[35]This was similar to my assumption in 1994.

emissions, or that purchases from UI would result in increased generation at UI's Bridgeport-3 coal plant.

- Coal is rarely on the New England margin, especially when oil and gas are as expensive as GMP was expecting in 1991. Oliver and Higgins acknowledge as much, by assuming that prices for spot energy purchases and pumping energy for Northfield escalate at the cost of #6 oil. Yet for externality purposes they assume, without documentation, that 36% of the Northfield pumping energy is coal.[36]
- Similarly, the comments Oliver and Higgins offer about externalities due to NiMo and NYSEG ignore the fact that the New York Power Pool (NYPP) performs economic dispatch, and energy for any sale from New York would be supplied by the marginal energy sources in the pool. Coal may have been the marginal fuel in New York for half the time in 1991, but this would decrease over time. In any case, roughly the same amount of energy is likely to be transmitted from New York to New England in any particular hour, regardless of whether there are capacity contracts or only economy energy transactions. Hence, the externalities due to purchases from New York should fall between the marginal fuel mix of NYPP and NEPOOL.

Finally, Oliver and Higgins make a very odd error in accounting for the externality effects of GMP transactions with the spot market. They assume that GMP's purchases from the spot market would increase emissions from oil-fired steam plants, but that GMP's sales into the spot market would not

[36]Since the dispatch of NEPOOL capacity depends only on NEPOOL load and capacity situations, a GMP purchase of Northfield capacity (or any other NEPOOL plant) would not change the dispatch of Northfield or of the units that might provide off-peak pumping energy.

reduce emissions from any type of generation. These sales occur in Oliver and Higgins's portfolio analyses (Portfolios 2, 3, 4, and 6) when GMP builds or purchases baseload capacity (such as a combined-cycle plant) that produces more energy per MW than the HQ purchase, or simply builds too much capacity.[37]

3. *Externality Valuation in Dollars per Ton*

Q: What externality values did Oliver and Higgins use for air emissions?

A: Oliver and Higgins used the values adopted by the Massachusetts Department of Public Utilities in DPU 91-131 (November 10, 1992), which were updates of the values the DPU adopted in DPU 89-239.

Q: What is their basis for using these values?

A: Oliver and Higgins state that these values existed in 1991, and that they are "more specific than the 5% adder." (IR DPS 2-45).

Q: Are these appropriate values for Oliver and Higgins to use in determining what resources GMP would have selected had it behaved prudently in 1991 and 1992?

A: No. It is difficult to understand why Oliver and Higgins use these values to estimate which resource GMP might have selected.

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[37]In IR DPS 2-67, Oliver and Higgins justify this treatment by asserting that they did not include the externalities of generating the excess energy that would be sold into the spot market. That assertion is simply untrue: in Portfolio 2 in 2005, for example, Oliver and Higgins assume that the gas combined-cycle would generate 900 GWh, as compared to the 750 GWh from the HQ purchase, and that the extra 150 GWh would be sold into the spot market. They include 900 GWh of combined-cycle externalities, but ignore the reduced externalities due to the 150 GWh sold into the spot market.

- GMP did not use these values in evaluating resource options in 1991–92, or since.
- As of 1991, GMP did not even have any coherent corporate view on the weight that should be accorded to environmental considerations.[38]
- GMP has never accepted any monetized values for externalities.
- GMP rejected the theoretical basis for the DPU externality values as recently as Docket No. 5980 (in the Lesser testimony of October 1997 and subsequent briefs) and in discovery in this case (IR DPS 2-47d).
- Oliver and Higgins did not use these values, or advocate the use of these values, in 1991–92.
- Their boss, Mr. Reed, testified against the DPU values in 1991-92 (IR DPS 2-44).
- Oliver and Higgins do not support or sponsor the DPU values in this docket (IR DPS 2-48). They do not argue that these were the best estimates available at the time, or that GMP or anyone else should have used them.
- The principal externality values presented in Vermont as of 1991–92 were those the DPS sponsored in Docket No. 5330, which were much lower than the DPU values.
- The Board did not adopt even the DPS externality values in the order in Docket 5330, although it did discuss the results of applying them.

[38] "This issue cannot be quantified without an internal policy decision regarding the Company's views on environmental externalities.…Two arguments against our quantifying the environmental costs of the NU units are: (1) the NU units are existing resources, and (2) emissions from the NU units would not ordinarily affect the air quality in Vermont" ("CoGen Lime Rock versus. NU Intermediate Offer," J. R. Letarte, 1991 IRP, Appendix 7-C at 3).

In short, Oliver and Higgins cannot be arguing that the DPU externalities *were* the basis for GMP's decision to lock in the HQ contract, nor that they *should* have been the basis for GMP's decision (e.g., given regulatory precedent), nor that typical prudent utilities were using those values. They may be arguing that someone *might* have used the DPU values in evaluating GMP's supply decisions in 1991–92. I do not see what relevance that assertion might have to the question of GMP's costs would be today if it had acted prudently in the early 1990s.

Q: Who might have used the DPU values in evaluating GMP's decision as to whether to lock into the HQ contract?

A: I might have. I developed some of the values the DPU used, and supported those values, or higher ones, in DPU Docket No. 91-131. So far as I know, Mr. Biewald and I were the only participants in the current proceeding who advocated externality values of this magnitude in 1991.

Q: Did you find the HQ contract to be least-cost at the time?

A: No. I testified against the contract in Docket No. 5330. The contract had little or no environmental benefit (as I describe above), and exposed the participants to excessive risks due to its size and inflexibility.

Q: Would the adoption of these externality values in 1991 have resulted in other effects on GMP's resource mix?

A: Yes. Much more DSM would be cost-effective at the DPU externality values. If those were the prudent values, then all of GMP's DSM planning was imprudent. If the Board were to accept that GMP should have conducted corrected computations of the type provided by Oliver and Higgins, combining their assumed high fuel costs with limited availability of low-cost power purchases and high externality costs for most resources, the Board would also have to find that GMP violated its obligations under Condition 8 of the order in Docket No. 5330 to pursue all cost-effective conservation. The avoided costs that GMP would have developed under Oliver and Higgins's approach would have been much higher than those it actually used in the 1991 IRP, and even further above the reduced avoided costs presented in 1992, and the extent to which it underutilized available DSM potential would have been correspondingly larger.

In addition, acceptance of the DPU externalities values would logically have affected GMP's positions on the many other planning and operational issues, including fuel choice at McNeil.

4. *Discounting of Externalities*

Q: How do Oliver and Higgins discount the monetized emission costs to derive a present value?

A: Oliver and Higgins use a real discount rate of 3% for externalities, even though they use a 7% real discount rate for all other costs.

Q: Is this treatment correct?

A: No. Oliver and Higgins offer no coherent basis for discounting direct costs and monetized emission externalities at different discount rates.

First, the Massachusetts DPU, whose externalities Oliver and Higgins adopt, used the same discount rates for direct and external costs.

Second, on discovery, Oliver and Higgins listed three texts that they asserted contained explanations for discounting externalities at a lower discount rate than direct costs (IR DPS 2-53). Oliver and Higgins provided no page cites, even though at least one of the books is 441 pages in length. I have not reviewed the text Oliver and Higgins cited that is authored by Jonathan Lesser of GMP. I have reviewed the two other texts (Lind and Cline), and can find no reference in either volume to using different discount rates for direct costs and externalities. Lind deals with adjusting discount rates to reflect risk, and explains how investments with different risk characteristics can be discounted differently. Cline argues that long-term public decisions should be based on low discount rates, and applies his low discount rate (about 2%–4% real) to both the costs of greenhouse mitigation and the avoided damages of global warming.

Third, Oliver and Higgins's sole argument (at 25) for using the lower discount rate for externalities is that using the utility's cost of capital as a discount rate would mean that the estimated present value of externalities would be sensitive to the utility's cost of capital. Their criticism of the use of the utility's cost of capital as a discount rate applies equally well to making decisions about direct costs to ratepayers. In the societal test, society bears all the costs: it is not clear why some societal costs should be discounted at 3% real and others at 7% real.[39] GMP and the Board have generally used the utility cost of capital as an estimate of the discount rate for society and for ratepayers, neither of which is easy to determine directly.

Fourth, by discounting emissions values at a lower rate than direct costs, Oliver and Higgins are implicitly assuming that it is worth more, in constant dollars, to avoid a ton of emissions in the future than it would have been be worth in 1991. This relationship is shown in Exhibit DPS-PLC-9, for

[39] Discounting all societal costs and benefits at 3% real would result in more cost-effective DSM than under GMP's traditional discounting at its own cost of capital.

the example of CO_2. Oliver and Higgins's approach would find in 1991 that spending $45 (in 1991 dollars which is more than $100 in 2010 dollars) in 2010 would be justified to avoid a ton of emissions in 2010, even though no more than $22 could be cost-effectively spent to avoid a ton of emissions in 1991. Neither the DPU nor any other regulator (so far as I am aware) has assumed this escalation of value for emissions.

Similarly, Oliver and Higgins's discounting approach would result in different decisions, depending on whether the decision is made in 1991, 1995, 2000, or 2010. For example, consider a situation in which CO_2 is valued at $24/ton and a measure is available that would avoid release of one ton of CO_2 for a cost of $30. Oliver and Higgins's approach would find in 1991 that this measure would not be cost-effective in 1991, but would be cost-effective in 2000: the present value of $24 of externalities nine years in the future is $18.39 at a 3% real discount rate, while the present value of $30 of direct costs nine years in the future is $16.32 at a real 7% discount rate. Of course, once the year 2000 arrived, and the costs were no longer discounted, Oliver and Higgins's approach would once again find that the measure cost $30 and saved only $24, and once again reject it. This is a nonsensical result.

Fifth, Oliver and Higgins have no opinion about the proper value of any externality, or how that value changes over time (IR DPS 2-48, 2-57, 2-58). Hence, they cannot support the dramatic escalation in emission values that they assume.

Sixth, it is not clear whether the environmental effects of various pollutants will rise or fall over time.[40] Even assuming that future environmental effects might be more costly than current effects, the implementation of differential discount rates by Oliver and Higgins is conceptually incorrect. The societal willingness to pay for emissions reductions, which is presumably revealed by the marginal cost of required emissions control, may reflect the regulators' view of the relative importance of future effects, from the time the effects are felt back to the time it is emitted. That discounting is already embedded in the emission valuation.[41] There is no theoretical basis for assuming that the social discount rate for monetized emissions—from the time the pollutant is emitted back to the present—would differ from the social discount rate for other costs. In short, while some differential discounting of environmental costs might be appropriate to derive emission prices, using a special discount rate to determine the present value of the emission prices is not valid.

5. *Conclusions on Externalities*

Q: What is the relevance of externality valuation to the prudence of GMP's actions with respect to the HQ-VJO contract?

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[40]Considerations relevant to this issue include whether the environment is getting cleaner or dirtier, whether adaptation and remediation techniques are improving or deteriorating, whether the effects are cumulative, and whether society as a whole is getting richer or poorer over time.

[41]The Board has previously found that externalities values that are based on the cost of controlling emissions—unlike those derived from damage costs—should not be discounted in special manner. "Use of abatement costs [like the DPU's] also avoids difficult issues associated with discounting future actual damages." (Docket No. 5330 at 185).

A: The relevance is very limited. These externality values were not the basis for GMP's decision to lock into the HQ contract; Green Mountain Power did not monetize externalities in 1991. Nor is it reasonable to suppose that GMP would have used these values later in 1991 or 1992, had it avoided the premature lock-in, since it has never adopted these or any externality values. Nor were most utilities using comparable values, unless they were ordered to do so by their regulators (as in Massachusetts). The emissions Oliver and Higgins used are unrealistically low for the HQ purchase, and unrealistically high for most of the alternatives, so the comparisons they have performed are not meaningful, even for someone (such as myself) who agrees with the dollars-per-ton values used in Oliver and Higgins's analysis.

In addition, were the Board were to accept that the externalities used by Oliver and Higgins were the appropriate ones for GMP to use in the early 1990s, it would create additional prudence problems for GMP. Much more DSM would be cost-effective at the high externalities values that Oliver and Higgins use, and GMP's failure to pursue that DSM would be imprudent and violate Condition 8.

D. Risk

Q: Have Oliver and Higgins demonstrated that the HQ contract would reduce risks to GMP and its customers?

A: No. Most of Oliver and Higgins's discussion of risk is abstract, unquantified, and unrelated to the HQ contract and its alternatives. While they spend about five pages (at 16–20) discussing various types of risk, they do not mention the HQ contract in this section, and provide no information on the relative risks of HQ and alternative resources. Their conclusion (p. 35, lines 17-21) that the HQ contract would have risk-reduction benefits is not supported by any analysis.[42]

Q: Do Oliver and Higgins deal with the risks of the HQ contract?

A: To a limited extent. Oliver and Higgins do acknowledge (at 17) that the fixed prices of the HQ contract would impose their own risks. They try to dismiss this concern by asserting that all contracts have risks, but they do not demonstrate that the inflexible fixed-price HQ contract was less risky than other options.

Oliver and Higgins do not respond to the issues raised in Docket No. 5983 regarding the risks imposed by the scale of the HQ purchase.

> Because it was large, long-term, "all-or-nothing", and contained very large fixed cost components, the Contract commitments had significant financial risks; Vermont utilities should have been especially diligent in monitoring and mitigating those risks. (Docket No. 5983, Order at 194)

Q: Should the HQ-VJO contract be treated as preferable to other resources in terms of risk?

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[42]Oliver and Higgins appear to understand that any effect of the HQ contract on risk would be limited to financial risk. Once the transmission connections are in place and the power plants built, the reliability of power supply to GMP, Vermont, or New England is determined by the reliability of the installed equipment and the laws of physics, essentially independent of the contractual arrangements that determine the flow of dollars. No NEPOOL utility will run short on power, so long as the pool can meet its total load, and transmission is adequate. Similarly, New York, Quebec, and New England (along with other adjacent power pools and utilities) provide whatever aid they can to one another in an emergency. Whether HQ sold its power firm or spot, short-term or long, to GMP, Boston Edison, or Con Edison, would not significantly affect the reliability of power supply for GMP.

A: No. As it was implemented, the HQ-VJO contract had risks at least comparable to alternative resources, especially for a utility with GMP's resource mix.

E. Portfolio Modeling

Q: Please describe the portfolios of alternative resources that Oliver and Higgins compared to the HQ-VJO purchase.

A: Oliver and Higgins construct six supply mixes in Exhibit WJO/JEH-7, each of which would provide the combined capacity and energy of GMP's share of the three HQ schedules (114 MW and 750 GWh from 1996 to 2013, less in earlier years and in 2014). These analyses (unlike Oliver and Higgins's busbar analyses) assume that all three schedules would be taken or canceled together. Of course, by 1992, Schedule A had been in effect since November 1990, so this assumption was not completely realistic.

Each portfolio starts with purchases of capacity and spot energy from the market through 1994. Except for Portfolio 5, which uses only spot-market purchases, each portfolio adds one or more major resource (NU baseload, NU intermediate, WESNEEX, combined-cycle or CT) in 1994 or 1995.[43] Oliver and Higgins compare the present value of their estimated cost of each portfolio to the present value of the HQ purchase, over the period 1990–2015, both for the direct costs (which they call "contract costs") and for the sum of direct and external costs (using their inappropriate estimates of externalities and their inappropriate discount rate).

[43]Portfolio 4 adds a small NU Baseload purchase in 1991.

The portfolio analyses contain numerous errors, conceptual and computational.

Q: What are the conceptual errors in the portfolio analyses?

A: In addition to the problems in the input assumptions that I described in IV§A and IV§B above, and the problems in the treatment of externalities in IV§C, the portfolio analysis is flawed in the following ways.[44]

First, Oliver and Higgins assume that portfolio capacity and energy must equal the purchases under the HQ-VJO contract, without demonstrating that this particular pattern of energy and capacity was required or cost-effective (IR DPS 2-147). If Oliver and Higgins had allowed the alternatives to consist of just the amount of capacity and energy GMP would have needed, the costs would likely have been lower.

Second, the portfolios are not least-cost.[45] Oliver and Higgins (at 37) made no effort to optimize the mix of resources. Their portfolios also sometimes do not match the capacity of the HQ purchase. For example,

- Portfolio 3 adds alternative capacity in 1995 that is not needed until 1996.

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[44]The various portfolios, and sometimes various years within a portfolio, or resources within a year, use different conventions regarding the treatment of partial years (for example, capacity added in October) and on the linking of computations. It is therefore difficult to review all the computations.

[45]Oliver and Higgins cite the decision analysis in the rebuttal testimony of Feinstein and Lesser in Docket No. 5983 as a guide to the constructing of their own portfolios (Oliver and Higgins direct at 38–39). It is not clear how Feinstein and Lesser guided the analysis of Oliver and Higgins, and in any case the Feinstein and Lesser did not really perform a decision analysis, did not optimize their portfolios, and made numerous unreasonable assumptions, as explained in my rebuttal testimony in Docket No. 5983.

- Half of the portfolios (Portfolios 2, 4, and 6) add too much capacity in 2004, the year the NU purchase ends and a combined-cycle replaces it. I am not sure what Oliver and Higgins meant to assume about capacity payments and capacity credits,[46] but in each case they included the costs of five months of a 114.2 MW of an NU purchase and a full year of 114.2 MW of a combined-cycle, to replace 114.2 MW of HQ capacity. This treatment double-counts GMP's capacity requirements, and results in spot capacity sales at costs below the purchase price.
- Oliver and Higgins do not consistently match the capacity and energy of HQ and the replacement resources. In 1995, when Schedule A ends and Schedules B and C3 start, Oliver and Higgins properly treat Schedule A as providing 9 months of capacity and Schedule B as providing 3 months, both for computing the costs of the contract and for determining the amount of capacity that would replace the HQ contract. For Schedule C3, Oliver and Higgins include only 2 months of costs, but assume that GMP would need to replace the capacity for all 12 months. This treatment increases the costs of all the replacement portfolios, requiring them to supply 75.5 MW in 1995, rather than the 36.7 MW that HQ averages over the year.
- Three of the six portfolios include the NU baseload purchase, which was more expensive that the NU intermediate purchase.

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[46] For example, a resource that entered service on October 1 could be assumed to provide a full year of capacity value (since it is before GMP's winter peak), $^{3}{}_{12}$ of a year (corresponding to the time it is in service in the calendar year), or zero (assuming that the capacity market is driven by summer-peaking utilities). Similar adjustments may be made to the capacity costs of resources.

Similarly, Oliver and Higgins made no effort to optimize the mix of spot purchases (or sales) and the generation from new GMP-owned plants or purchase contracts. Nor did they properly model the costs of the spot purchases. For example,

- In each of the non-spot portfolios, Oliver and Higgins add too much baseload capacity (or sometimes too much capacity, as noted below), and sell power into the spot market at a loss.
- In Portfolios 3 and 6, in 1994 (the last year in which they assume major spot power purchases), Oliver and Higgins include the costs of supplying the equivalent of the HQ energy from both spot purchases and from an NU purchase. For example, Portfolio 3 replaces 70.1 GWh of HQ energy in 1994 with 57.9 GWh of spot purchases and 72.9 GWh of NU baseload, or a total of 130.8 GWh.[47] If Oliver and Higgins meant to add the 72.9 GWh of NU baseload, the spot market transaction should have been a sale of 2.8 GWh, not a purchase of 57.9 GWh. They nearly double-count energy requirements for this year.
- Oliver and Higgins use the price of baseload energy purchases that they computed from GMP's 1991 assumptions for off-peak purchases to supplement intermediate sources, such as the NU intermediate purchase.[48] The off-peak spot prices should be lower than baseload. Oliver and Higgins recognize that fact, in assuming that off-peak pumping energy for Northfield Mountain would cost 2.3¢/kWh in 1990, compared to 4.1¢/kWh for baseload spot energy.

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[47]Portfolio 6 replaces the same 1994 HQ energy with 70.1 GWh of spot purchases and 11.7 GWh of NU intermediate.

[48]This computation was incorrect, as I describe above.

Third, having assumed excessive off-peak spot prices, Oliver and Higgins assumed that GMP would use that spot energy, even though the price is greater than the energy costs for the oil-fired intermediate plants. For example, in 1996, with the 5/91 WEFA prices), Oliver and Higgins assumed that GMP would purchase oil-fired capacity that could run at an 87% capacity factor and 4.0¢/kWh, run that capacity at just 50%, and then purchase replacement spot energy at 4.7¢/kWh.

Fourth, Oliver and Higgins consider only the period of the HQ contract, and use the nominal ratemaking costs for combined-cycle and combustion turbine units, not the real-levelized costs. They ignore the benefits in these case of the value in 2015 of having a 10-year-old, largely depreciated power plant.[49] Since Oliver and Higgins demonstrated in their Exhibit WJO/JEH-6 that they know how to compute real-levelized costs, their error was entirely unnecessary.[50]

Q: What are the computational errors in Oliver and Higgins's portfolio analysis?

[49]In IR DPS 2-170, Oliver and Higgins argue that "real-levelized revenue requirements cannot simply be 'added up' to determine an overall portfolio cost." They are wrong. It is nominal annual ratemaking costs that "cannot simply be 'added up'" without some treatment of end effects.

[50]Ironically, this issue arose in Docket No. 5983, where GMP agreed that real-levelized costs should be used in this situation, but argued that it was not imprudent in failing to do so in its 1991 IRP, because the method was not then yet established (Saintcross rebuttal at 54–55). Regardless of the merits of GMP's argument in Docket No. 5983, concerning what was reasonable in 1991, the Oliver and Higgins treatment of the ratemaking costs of new power plants was clearly unreasonable in 1998.

A: There are several such errors. First, For the purpose of computing the nominal discount rate, Oliver and Higgins attempt to use WEFA inflation rates that vary from year to year. Rather than accumulating the inflation rates from year to year, they compute inflation to some future year (say 2005) as the inflation rate in that year for each year since 1991.

Second, the one portfolio that uses the NU intermediate option (Portfolio 6)

- contains an incorrect reference, and uses the total busbar cost of the plants where it should have been using the energy cost.
- understates externalities for the NU intermediate purchase by 90%, compared to the values Oliver and Higgins intended to use, because they failed to convert from cents per kWh to dollars per MWh.
- computes the NU intermediate energy production in 2004 as $^{5}/_{12}$ of a full year's production, and also includes a $^{5}/_{12}$ adjustment in the energy price computation, resulting in counting less than half the energy cost that Oliver and Higgins intended for that year.
- excludes the NU intermediate capacity charges from the computation of total direct costs, but does include the externality costs for the NU intermediate purchase (which are counted twice in the societal cost).

Third, capacities of the portfolios do not always add up. For example, in Portfolio 1, Oliver and Higgins add 92.8 MW of combined-cycle and 21.4 MW of CT (a total of 114.2 MW) to replace 75.5 MW of HQ in 1995, which should produce a surplus of 38.7 MW to sell into the spot market.[51] Yet Oliver and Higgins assume that that non-HQ portfolio would sell 98.2 MW

[51] As I note elsewhere, the 75.5 MW is itself an error, since it includes a full year of Schedule C3, which Oliver and Higgins assume would be on line for only two months of 1995.

into the market (although they limit this sale to nine months with an ad hoc adjustment).

Fourth, Oliver and Higgins advance the NU intermediate costs by nearly one year, in converting the offered rates from power years (November-October) to calendar year (January–December). For example, they compute the 1995 capacity charge as two months of the 1994–95 rate, plus ten months of the 1995–96 charges, rather than ten months of the 1994–95 rate and two months of the 1995–96 rate. It is not clear why Oliver and Higgins made this mistake, since the error required them to assume that the 2003–04 costs would be in effect for 15 months, and since they did not make the same mistake with respect to the NU base costs (which were not likely to be competitive in any case).[52]

Q: Have you corrected any of Oliver and Higgins's analyses?

A: Yes. I have removed the computational errors that I identified from Oliver and Higgins's analysis of Portfolio 6 (NU Intermediate followed by gas combined-cycle) for the WEFA 9/92 fuel prices. I also corrected several of their assumptions, as follows:

- To supplement the NU intermediate units, I used the cost of off-peak spot energy that Oliver and Higgins estimate for Northfield pumping energy, rather the cost of baseload spot.
- I eliminated their duplication of energy supply and capacity requirements.
- I real-levelized the combined-cycle carrying charges.

[52] Since Oliver and Higgins do not provide the other utility sales and offers, I cannot tell whether they made the same mistake elsewhere.

- I used the realistic gas pipeline charges I discussed above.
- I properly computed the calendar-year costs for the NU intermediate purchase from the power-year cost.
- I eliminated the externality costs, which would be essentially the same for both options

As shown in Exhibit DPS-PLC-10, these corrections decrease the present value of the replacement portfolio from $341 million to $298 million, while the cost of the HQ contract remains at $322 million.

This corrected analysis still does not compare the HQ-VJO purchase to a least-cost portfolio. For example, the NU purchase does not include any Northfield Mountain pumped-storage capacity, the alternative portfolio is designed to match the HQ resource rather than GMP's needs, and the portfolio does not include the lower-cost purchases that were available by 1992. The least-cost portfolio would be less expensive than Portfolio 6.

V. Other Issues Related to GMP Imprudence

Q: What other prudence issues are addressed in the testimony of the GMP witnesses?

A: Oliver and Higgins appear to challenge the economic basis of the Board's imprudence finding in Docket No. 5983. Witness Reed reargues prudence standards.

A. Issues in Oliver and Higgins's Testimony

Q: How do Oliver and Higgins attempt to reopen the issue of GMP's prudence in the early lock-in decision?

A: Oliver and Higgins do not testify in support of GMP's actual analyses performed in 1991, and Reed indicates that Oliver and Higgins are not disputing the Board's finding of imprudence relating to GMP's planning. However, they do accept several of GMP's actions that led to the premature lock-in and that the Board found imprudent, such as GMP's failure to investigate power-purchase opportunities from New York and failure to use the "low" fuel-price forecast in evaluating the HQ contract. They also perform analyses of the cost-effectiveness of the HQ contract at the fuel prices GMP used early in 1991, effectively revisiting the question of whether GMP should have committed to the contract in August 1991.

A simple reading of the testimony of Oliver and Higgins suggests that they are primarily asking a question that is not at issue in this case: whether deciding to go forward with the HQ contract would have been prudent at the time of the lock-in, later in 1991, or in 1992.

Q: Do Oliver and Higgins state a purpose for their testimony?

A: Yes. In their testimony (at 5–6), they say that their purpose "is to provide a quantitative assessment of the economics on a societal cost basis of the HQ/VJO contract relative to other resource options…given the Board s suggestion that a delay might have revealed better power resources…[and] given the market knowledge available to resource planners."[53] This description suggests that they are reviewing the prudence of GMP's commitment to the HQ contract, rather than attempting to determine the resources GMP would have selected after the cancellation of the HQ-VJO contract, and the estimation of damages from GMP's imprudence.

[53] They also mention that they present an economic used-and-useful test for the contract.

Oliver and Higgins's testimony might be read as an attempt to demonstrate that, even if GMP's decision-making process in 1991 was imprudent, that prudent analyses would have lead GMP to lock into the HQ contract in 1991 or 1992. However, on discovery, GMP described this issue as being a subject of the appeal in Docket No. 5983, and refused to state whether Oliver and Higgins were attempting to make this demonstration (IR DPS 2-172).

Q: Have Oliver and Higgins demonstrated that GMP would have reached the conclusion that the HQ contract was cost-effective, if it had conducted prudent analyses in 1991 or 1992?

A: No. They did not use information available to GMP, including fuel price projections, and made many unreasonable assumptions.

Q: Have Oliver and Higgins demonstrated that some prudent person might have reached the conclusion that locking into the HQ contract was appropriate, given the information that was, or should have been, available to GMP?

A: Not really. The benefits of the HQ contract were small, even with fuel prices higher than GMP believed, at the time of the premature lock-in. The lock-in provided no benefits, at a very high potential cost. Even if one really believed the WEFA fuel-price forecasts, rather than the lower forecasts GMP believed, several resources had lower direct costs than HQ by September 1992. HQ could only be prudent if it had environmental benefits for which Oliver and Higgins have provided no evidence. The benefits are unlikely, and in any case, neither GMP nor Oliver and Higgins believed the externalities valuations.

In any case, in reviewing the prudence of GMP's decisions, Oliver and Higgins do not use either information the GMP had (such as a lower load forecast) or that GMP could have known (such as the availability of the New York purchase options).

B. Prudence Standards

Q: Has Reed properly delineated the prudence standard applicable to utility ratemaking determinations?

A: No. His testimony on the prudence standard closely parallels (and repeats large sections of the text of) his testimony with Mr. Oliver in Docket No. 5983. He presents two sets of prudence standards, and then quotes the Vermont Supreme Court and the Board. From the latter quotes, he concludes (at 13) that "only imprudent costs should be excluded."[54] So long as the subject is the prudence test, I agree with him that only imprudent costs should be excluded from recovery on the grounds of imprudence.

Q: What are the two sets of prudence standards Reed proposes?

A: The first set of standards that Reed lists (at 7–11) are not attributed to any source, and appear to be his own opinions. The three principles Reed proposes (with some editing for brevity) are as follows:

[54]Actually, Reed quotes from the Vermont Supreme Court states that "excessive" expenses can be excluded from rates, even if they were warranted and incurred in good faith. "Although expenses…should be scrutinized with care, the Commission had no authority to disallow or reduce them unless it clearly appeared that they were excessive or unwarranted or incurred in bad faith" (*Latourneau v. Citizens Utilities Co.*, cited by Reed at 12). This suggests to me that the Court anticipated the exclusion of some prudent expenses, based on an economic used-and-useful test.

> 1. The prudent management standard must be able to be consistently applied across a wide range of circumstances; the application of the standard should not be dependent upon the nature of the costs being reviewed or the rate resulting from the application of the standard.
>
> 2. ....[I]n order for a cost to be disallowed, the decision must be demonstrated to be outside the range of reasonable behavior based on circumstances as they existed at that time.
>
> 3. The prudent management standard must adequately balance the interests of ratepayers and investors, and provide a reasonable incentive for the utility to provide reasonable service at a reasonable cost.

Q: Are the principles proposed by Reed appropriate?

A: While the operational meaning of the proposed principles is far from clear, they do not appear to properly reflect the concept of prudence usually applied to utility management.

Reed's first proposed principle would be difficult or impossible to implement. The standards that one would apply in evaluating the prudence of maintenance of a valve at Vermont Yankee would necessarily be stated in different terms than the standards that would apply in evaluating the prudence of management oversight of a major power purchase.[55]

The third proposed principle inappropriately asks the prudence standard to "adequately balance the interests of ratepayers and investors," which is a goal for the overall ratemaking process. The prudence standard is only part of the balance.

Reed's second principle is the most troublesome, as it may represent his attempt to change the prudence standard from "Did GMP behave prudently,

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[55] I made the same point in Docket No. 5983, and Reed has not clarified his intention, or explained how this test would be applied in any realistic setting.

given the information available (or that should have been available) to the Company at the time?" to "Could anyone have reasonably made this decision, given circumstances as they existed at that time?" The same problem recurs in the testimony of Oliver and Higgins, as I discuss below.

Interestingly, Reed's second principle is inconsistent with the single Board precedent he cites:

> The prudence of a utility's business decision must be viewed from the perspective of the utility at the time it made its decision. (Docket No. 5532 at 18, quoted by Reed at 13)

The question is not whether someone *might* have believed in 1991 that oil and gas prices were likely to rise rapidly in future years, that New England capacity supply would become very tight, and that spending large amounts of money to reduce the environmental impact of electric generation was justified.[56] The question is whether GMP behaved prudently, given the information available to it.

Q: What is the second set of standards Reed articulates?

A: The second set is quoted from a 1985 NRRI report, and includes the following:

- Utility decisions should be presumed prudent.[57]
- Reasonableness must be judged under the circumstances.
- Hindsight should be prohibited.
- Determine prudence in a retrospective, factual inquiry. "Testimony must present facts, not merely opinion." (Reed and Oliver, 7–8)

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[56]This latter point would need to be combined with some factual errors about the impacts of the contract to produce any apparent benefit for the HQ contract.

[57]I assume that the original source indicates that this assumption is rebuttable.

Q: Did the Board's investigation of GMP's prudence in Docket No. 5983 meet these standards?

A: Yes. The Board's order in Docket No. 5983 did just this. It reviewed the reasonableness of GMP's behavior *under the circumstances* (including the scope of the commitment, the changing nature of energy markets, and GMP's own beliefs about fuel and power prices), *without hindsight*, in a *retrospective, factual inquiry*. The fact is that in 1991, GMP knew it was approaching a final decision on its most important power supply decision, and failed to examine seriously alternatives or even review the economics of the contract using the Company's own fuel-price assumptions. Had GMP looked seriously at alternatives and compared them to HQ in the same manner that GMP evaluated DSM, it would not have prematurely locked into the HQ-VJO contract in August 1991. Subsequent evaluation of alternatives would eventually have led GMP to negotiate a substantially lower-priced contract with HQ or some other utility.

Q: Do Oliver and Higgins apply the NRRI standards in their testimony?

A: No.

VI. The Company's Distributed Utility Planning Efforts

Q: Please summarize the exchange between the DPS and GMP regarding DU planning in Docket No. 5983.

A: The Department expressed concern with the following aspects of GMP's efforts to pursue DU planning:

- Errors in the assumptions underlying the Mad River Valley Study (GMP's sole DU planning exercise at that time).

- Failure to understand the import of the problems with its analysis.
- Lack of interest in correcting those problems in future DU planning efforts.
- Overly enthusiastic representation of the results, and apparent satisfaction with, its previous unsuccessful DU efforts.
- Arbitrary selection of DU planning target areas and schedules.
- Excessive concentration on modeling, especially the modeling of uncertainty, rather than on planning and acting to reduce costs.
- Failure to integrate DU planning efforts within the Company.

In short, GMP's DU planning efforts had produced no concrete results, and showed no sign of doing so in the future. The Department concluded that, if its DU planning were ever to produce concrete benefits, GMP would need to thoroughly rework its approach, move beyond grand concepts, and grapple with the real interdisciplinary issues of DU planning and implementation.

Green Mountain Power responded by conceding many of its past problems, but attacking the Department's DU approach as asking the wrong question and leading to uneconomic investments. Green Mountain Power opposed using DU planning as a means for reducing total social costs, and particularly opposed consideration of energy savings.[58] The Company also insisted that the proper treatment of uncertainty was critical to effective DU planning, and advocated suspension of DU planning until a new model, then under development by EPRI, was available.

[58]These positions were laid out in GMP's case in Docket No. 5980, much of which was incorporated in the record in Docket No. 5983.

Q: Did the Public Service Board, in its Order in Docket No. 5983, address the shortcomings that you discussed in your testimony in that case?

A: Yes. On page 156 of its Order in Docket No. 5983, the Board stated that "we fully expect…that, in its on-going DU activities, the Company will address the concerns raised by the Department in this case, and take all appropriate steps to refine its methods."

Q: What has GMP done with regard to DU planning since Docket No. 5983?

A: In February 1998, Green Mountain Power released a DU planning study for the Dover-Wilmington area, using the EPRI Area Investment Planning Model (AIPM), on which GMP placed such reliance in Docket No. 5983.

In May 1998, GMP and EPRI made a two-day presentation to the DPS and a representative of the Board on the AIPM and Dover-Wilmington study. The shortcomings of the model and the study were obvious to the DPS participants, who pointed out several inconsistencies and errors during the meeting. Despite this frank discussion, "GMP is not aware of any problems with Version 1.01 of the [AIPM] model" (IR DPS 2-222).

The report I prepared for the Department on the AIPM and the Dover-Wilmington study is attached as Exhibit DPS-PLC-11. Additional comments by Steve Litkovitz of the Department staff are attached as Exhibit DPS-PLC-12. These reports discuss the Department's concerns regarding GMP's significant investment in, and resource demands of, the AIPM and the resulting DU planning process. The reports suggest that other strategies for evaluating DU planning opportunities may be more flexible and better suited to GMP's needs.[59]

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[59]The Department's review of the AIPM has been hampered by EPRI's refusal to provide a copy of the model, or even the user's manual, without onerous confidentiality conditions. For

Q: Has the Department communicated to GMP its concerns regarding GMP's DU planning process, the adoption of the AIPM model, and the resulting effects on GMP's overall implementation of effective DU planning?

A: Yes. The Department provided both reports to GMP.

Q: Please summarize your report on the AIPM.

A: The AIPM represents an ambitious effort to automate the complex problem of distributed utility planning, incorporating local transmission and distribution constraints, traditional engineering solutions, DSM, and distributed generation.[60] As discussed in more detail in Exhibit DPS-PLC-11, the AIPM fails to achieve its goal for the following reasons:

1. The model does not allow for modeling of the multiple constraints commonly found in the toughest problems in DU planning.
2. The load-growth model is limited to only five load-growth states, which is inadequate for many real problems.
3. The AIPM transforms assumptions about annual load-growth possibilities into a three-branch approximation of growth rates until new capacity is needed. After the addition of new capacity, the model

example, EPRI would prohibit anyone who reads the manual from in any way publicly "disclosing the model," which might prevent the disclosure of the numerous errors in the model. This model, even if it were otherwise corrected, would not be useful in a planing process that is subject to public review, without wide public access to the documentation and the model.

[60]Distributed utility planning must reflect both the local costs and benefits of investments made and avoided, operating costs, and line losses, and also the system-wide costs and benefits that result from changes in local energy usage or production.

repeats the approximation procedure. This step produces very serious problems, especially where load additions are lumpy.

- The model assumes that remaining capacity can be used up in fractions of a year, ignoring the annual cycle of load.
- The model forgets about any part of a load addition that exceeds the remaining capacity.
- The load model is re-estimated after an resource decision, the model has no means of determining whether load-growth possibilities (such as major customer expansions) have already occurred. A potential (even likely) expansion can be forgotten by the model, or a unique event may be repeated.

4. The AIPM does not deal well with the system benefits (avoided costs, line losses and unserved energy) or even the hours of operation of distributed resources.
5. The model does not provide for distributed resources whose scale or cost varies with load growth, such as new-construction DSM, or distributed generation associated with new load.
6. The model simplifies lead time in ways that limit its realism and its value in making decisions to implement resources with lead times.

The AIPM may be useful in DU planning situations involving a single constraint, a large number of relatively small potential load additions, and no large potential additions. This does not appear to be a common situation in Vermont. Even in the best of circumstances, the current version of the model does not accurately represent the characteristics of DSM or distributed generation.

Q: Please summarize your report on the Dover-Wilmington study.

A: In addition to the problems inherent in the AIPM, the Dover-Wilmington study has a number of errors that prevent it from providing useful planning guidance. The model was set up to minimize the expected cost of T&D additions, DSM and distributed generation to meet potential growth at the Mt. Snow ski area.

1. The load-growth modeling is oversimplified, due to constraints in the model. Green Mountain Power assumed that no growth would occur in the Dover-Wilmington area prior to the 8-MW first phase of a major expansion at Mt. Snow. A second 5-MW phase of expansion at Mt. Snow might occur immediately after the first phase, or not at all. Following whatever expansion occurred, ancillary load growth would occur at 1–2% annually. The model s structure prevented GMP from allowing for any possibility of ancillary load growth before the Mt. Snow expansion or between the first and second phases of the expansion, or even any delay in the second phase.

2. It is not clear that the model inputs reflect the nature of the planning problem.

   - The model ignores the fact that Dover-Wilmington load is slightly below capacity, and forces an immediate resource addition.
   - Green Mountain Power asserts that Mt. Snow has already managed the shape of its loads so that further interruptibility (as in the Sugarbush contract that resolved the Mad River Valley constraint, at least temporarily) is not feasible, but also assumes that loads are very sharply peaked, which would imply that further load management should be feasible.

- Most importantly, the Mt. Snow expansion would use up most of the remaining transmission capacity into the Dover-Wilmington area; while GMP recognizes that further transmission capacity would be very expensive, the model does not reflect the potential for future major load growth beyond the current plans, nor the costs of meeting that load.

3. In many situations, the model ignores some or all of the second phase of expansion at Mt. Snow, resulting in load growth much lower than the levels GMP specified in the inputs.
4. The study assumed no fuel costs for fuel-switching, and ignored all other customer costs of DSM.
5. The treatment of distributed generation and DSM is generally half-hearted and sloppy.
   - Avoided costs are far too low, and are unrealistically assumed to be the same for DSM and distributed generation.
   - Cogeneration is rejected with little analysis.
   - The range of distributed-generation technologies considered is very narrow.
   - The scope and peak contribution of DSM programs are limited in ways that appear to be arbitrary and inconsistent.
6. Green Mountain Power specified a 7.73% nominal discount rate, which appears to be rather low.
7. The study did not consider new-construction efficiency improvements, either as DSM programs or as part of the Act 250 process.
8. Green Mountain Power ignored line losses, as well as unserved energy.

The Dover-Wilmington study is not realistic enough to be of any direct application. In addition, the incidental and fundamental limitations of the AIPM make it difficult to apply usefully to the Dover-Wilmington situation.

Q: Is GMP actively pursuing Distributed Utility planning?

A: No. Green Mountain Power considers the Mad River Valley DU effort to be over,[61] is unwilling to act on the Dover-Wilmington situation until Mt. Snow "commits to a specific expansion plan" (IR DPS 2-218b), and has delayed the DU study previously planned for the Bellows Falls area due to financial constraints (IR DPS 2-194, 2-218c).[62]

At this time, the only DU activity Green Mountain Power reports is the beginning of a DU planning study for the Tafts Corners area of Williston (IR DPS 2-218d). For this study, GMP intends to use the AIPM model (IR DPS 2-223).

Q: Has GMP addressed the concerns that the Department raised in Docket No. 5983?

A: No. On the contrary, the events of 1998 have raised even further concerns about GMP's approach to DU planning. Not only does the long list of old

[61]As I noted in Docket No. 5983, GMP has not demonstrated that the problem it set out to solve in the Mad River Valley has been resolved in the long term. If Sugarbush finds that it is no longer able to operate within the available capacity limits, GMP may find itself scrambling to increase capacity, having lost many opportunities for energy efficiency (and perhaps distributed generation) in the meantime.

[62]As I noted in Docket No. 5983, it is not clear that Bellows Falls is a suitable site for DU planning, given the advanced state of voltage conversion and pressures to build a new substation, unrelated to load. Bellows Falls is an example of GMP's difficulty in articulating a policy for prioritizing DU planning opportunities: if this area was ever a suitable target for DU planning, that planning should have started years ago.

problems remain, but GMP appears to remain committed to the use of the AIPM model which is seriously limited in the respects detailed above. The one promising development is that Tafts Corner actually appears to be an area appropriate for DU planning. However, it is unlikely that the AIPM will produce meaningful results for the Tafts Corner DU study, especially if the GMP does not improve its ability to formulate the area-specific problems and potential resources.

Q: What conclusions do you reach regarding GMP's DU planning process?

A: My conclusions are discouragingly similar to those that I presented in Docket No. 5983:

- GMP continues to approach DU planning as an intellectual exercise, focusing on modeling for uncertainty, rather than as a serious utility planning activity focused on reducing costs.
- The AIPM would be useful only in the most limited situations. Green Mountain Power should not be relying on the AIPM to solve its DU planning problems.
- The Dover-Wilmington study demonstrates that GMP has not developed methods for producing appropriate inputs and assumptions for DU planning. There is no evidence that GMP has critically analyzed the process used for the Dover-Wilmington study, or that it will be able to do any better in the Tafts Corner study, especially given the burdens of developing inputs to the AIPM.
- Despite the Board's Order in Docket No. 5983, GMP appears to be satisfied with its efforts to date and has taken no real interest in addressing the concerns raised by the Department.

- There is no indication that internal coordination of DU planning has improved.

Q: How much money does GMP request for DU planning in this proceeding?

A: The Company requests $270,000 for "DU Project 97/98" (IR DPS 1-144a), which may include $29,840 paid to EPRI for the AIPM (IR DPS 2-225). The remainder is presumably related to the Dover-Wilmington study. To date, the AIPM has been an utter failure, which does not work as promised, and whose use by utilities is hampered by EPRI's excessive confidentiality requirements. Green Mountain Power should request a refund from EPRI, unless the model problems (which GMP claims not to know about) are fixed promptly. Since the Dover-Wilmington study appears to have been performed entirely in-house, and no actual implementation resulted, I do not understand how the project could have so expensive.

While I fully support utility efforts to develop DU planning, even with the understanding that not all efforts will be fruitful, I believe that GMP should better document the basis for spending so much to achieve so little.

Q: Does this conclude your direct testimony?

A: Yes.